The Petroleum Situation

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PETROLEUM SITUATION – NOW QUARTERLY

With the prospect of our publishing other newsletters on specific energy-related subjects, of which the **Coal Situation** *is an initial example, we have decided to issue each such publication on a quarterly basis. To bring it in line, this is the first quarterly issue of the* **Petroleum Situation**. *With this change, we are also enhancing the price/cost statistical data to cover more international information.*

INTRODUCTION

The North Sea has rapidly become one of the most important producing areas in the world outside North America and the Middle East. Its oil production is set to provide 7% of Free World output by the middle of the decade. Not only is the magnitude of North Sea output important in its own right, but the political security of Western European production is an important cushion against further OPEC crises. The North Sea industry provides one of the more important examples of a successful response to the threats to supply and the price upheavals experienced during the 1970s. While exploration and production began before the 1973 crisis, the majority of the fields now producing would have been uneconomic without the price revolution of the 1970s. The actions of OPEC have therefore provided both the strategic incentive and the economic underpinning for the development of the high-cost, high-risk North Sea fields.

Roughly $55 billion in constant 1981 dollars have already been invested on field development projects alone in the North Sea. Including the costs of exploration and operations, the total may be as much as $80 billion. The U.K. has consumed the lion's share of investment to date.

But this huge investment has generated commensurately large rewards. After production began in 1967, output grew steadily until it reached 500 thousand barrels per day oil equivalent at the time of the 1973 Middle East war. At that time, essentially all North Sea production was of U.K. Southern Basin gas. By the mid-1980s, the existing producing fields, and others already under development, will be producing almost 5 million barrels per day oil equivalent, a 10-fold increase over the decade.

Looking forward to 1990, more than $100 billion in constant 1981 dollars will be required to complete development of fields now under way, and to begin development of other fields which have already been discovered and proved commercial, but which are not yet at the construction stage.

HISTORY

The current North Sea development did not begin with the oil crises of the 1970s. North Sea exploration is the most recent evolutionary stage in 100 years of continuous European exploration and production activity. Exploration and production has gone on just as long in Europe as it has in the U.S., although on the surface the low oil output prior to the mid-1970s would seem to belie this.

Some sources put commercial production of oil in Poland and Romania two to three years prior to the Drake Well in Pennsylvania. Unfortunately for the countries of Western Europe, the fundamental geological potential for oil and gas in the *onshore* areas is very poor compared to North America. The huge, early U.S. oil discoveries, like Spindletop or the East Texas Field, shallow enough to be within reach of the early drillers, simply did not exist in Western Europe.

In consequence, the main focus of oil exploration by British and Dutch oil companies was directed at a very early stage towards the more promising areas of their respective colonial or mandated territories. The British initially explored Iran, with the forerunner of B.P. making its first discovery at Masjid-i-Sulieman in 1908; while the Dutch explored Indonesia, where the pioneering work was conducted by the forerunners of Shell, and major discoveries were made as early as 1893.

On the other hand, Germany, and to a lesser extent France, continued onshore European drilling despite the poor prospects, possibly because of more limited colonial opportunities. Germany has consistently been the biggest onshore oil producer in Western Europe, producing around 5 thousand barrels per day at the turn of the century, 50 thousand barrels per day during the Second World War, and during the 1950s achieving a peak of 100 thousand barrels per day.

During and immediately after the Second World War, a productive trend in northern Germany was extended into Holland. The Shell-Esso combine, known in Europe as NAM, became active in the 1950s in this area, and as their drilling technology improved and targets deepened to ten thousand feet or deeper, a number of gas discoveries were made in the so-called Rotliegendes sandstone. The culmination of this exploration play, and the key event which triggered North Sea exploration, was the discovery of the giant Groningen field in 1959. The initial reserves in this field were some 80 TCF, which constituted one of the biggest gas discoveries ever made. The high productivity of the wells meant that this single field could become the basis for the conversion of the continental European gas industry from manufactured to natural gas, and lead to a dramatic expansion in gas consumption, particularly in the Benelux countries and Germany.

The location of the Groningen field close to the North Sea shoreline, and geological evidence that the same Rotliegendes Sand outcropped at the other side of the North Sea in Eastern

England, suggested that the southern North Sea, which lies between, was a good gas prospect. Fortunately, water depths are modest in the area, within reach of then-contemporary technology borrowed from the Gulf Coast.

It took 5 years to decide how the Continental Shelf of the North Sea should be divided between the littoral countries before drilling could start. After resolution of these issues, B.P. quickly made the predicted gas strike in Rotliegendes Sand in the West Sole Field off the U.K. in 1965. 25 TCF of gas were quickly proved up in a string of fields, and the U.K. began a transition to natural gas in 1967.

Logical moves into more northerly, deeper waters, and into harsher weather and sea conditions took place during the late 1960s and early 1970s. The first North Sea oil was recovered in Danish waters in 1966, to be followed by the discovery of the giant Ekofisk, Forties, and Brent Fields, and the other mainstays of today's production.

GEOLOGICAL POTENTIAL

Recoverable reserves of about 24 billion barrels of oil and 140 trillion cubic feet of gas have been discovered in the North Sea to date. The smaller countries, Holland, Denmark, and Germany, have no more than 5% of offshore reserves between them at present. Britain and Norway have roughly a half each of the remainder. There is considerable geological potential for further discoveries in the area, but the likely distribution of new reserves could be markedly different to the split on current reserves.

United Kingdom

The U.K. has seen the majority of drilling so far, and the main producing fairway in the middle of the North Sea is readily becoming a mature producing province on the U.K. side of the median line. This is very likely to result in future individual discoveries being significantly smaller than current fields. Diminishing returns in general are likely to affect future exploration. It is generally accepted that all of the U.K.'s giant fields have already been discovered in this fairway area.

Although the Southern North Sea Gas Basin is also mature, there are many sparsely drilled, semi-proven gas fields needing further attention, and many small- to-medium-sized structures as yet undrilled. Future reserves to be discovered in this area could be as large as already proven reserves.

Outside the current producing areas, the Southwest Approaches and the Celtic Sea have been very disappointing, even though drilling efforts have so far been limited. The Irish Sea has some gas potential, and west of the Shetland Islands, a 10-billion-barrel oil field has been discovered, but well rates are sub-economic at current prices. There may be a number of modest but interesting structures to drill in the English Channel. The 90-million-barrel recoverable Wytch Farm oilfield discovered in the mid-1970s just onshore in Dorset, southern England, in all probability extends offshore. Finally, the virgin area west of Scotland has unknown potential, but the areas in moderate water depths are relatively limited.

On the whole therefore, while the U.K. will remain an interesting area to drill for decades to come, future discoveries are likely to be significantly smaller than in the past. The majority of the U.K.'s ultimate reserves may already have been discovered.

Norway

Norway, on the other hand, still has tremendous potential for giant discoveries, both in the central North Sea area, and in huge virgin areas north of the 62° parallel, which was the northernmost limit of licensed area until recently.

Apart from the Ekofisk area, which is now relatively mature, the rest of the fairway up to Statfjord is sparsely drilled compared to the U.K. As an indication of the continuing potential of this area, a surge of drilling in 1979 and 1980 on newly licensed acreage led to several giant discoveries. The most important of these are the prolific Statvik field in Block 34/10, with 1.3 billion barrels or more recoverable, and the huge Block 31/2 gas discovery which, together with probable extensions into adjacent blocks, could have potential Groningen-sized gas reserves with sizeable volumes of oil in addition.

The virgin areas north of 62° hold exciting long-term prospects. A first look at their potential was made in 1980, when three blocks were drilled off the northwest coast for the first time. Statoil made a minor discovery in the first well, in similar geology to the prolific fields 800 miles to the south. While this particular discovery is unlikely to be economic, it does indicate that a new hydrocarbon-rich province exists off the northwest coast. More recently, follow-up drilling in the 1981 season has confirmed a number of gas finds, one at least of which could be of giant status, with 5 trillion cubic feet or more of reserves. These fields could form the basis of an LNG export project, though first production is unlikely before the 1990s.

Looking even further north, there is a huge region in the Arctic and Barents Sea which is prospective in relatively shallow water depths, and which has seen no drilling so far. There is a boundary dispute in the Barents Sea with the Russians, where the area under dispute alone is greater than the entire currently licensed area south of the 62° parallel! In the long run therefore, Norwegian reserves could greatly exceed those of the U.K. and the rest of the North Sea put together. The pace of exploration and development will, however, be dictated by Norwegian political considerations, and is unlikely to be especially rapid.

SATISFYING EUROPEAN GAS DEMAND — THE ROLE OF THE NORTH SEA

The European Community is committed to an increased role for gas in the energy mix, to reduce dependence on oil imports. Its share of the primary market is expected to continue to rise, from around 13% today to 17–20% in 1990. Gas consumption in 1980 exceeded 22 billion cubic feet per day.

The main mechanism for increased market share is displacement of high-priced heating oil from the domestic heating market. At the same time, a loss in gas marketed to the industrial and power generation sectors is likely, as gas continues its progress to a premium fuel status and loses non-premium customers back to oil and, increasingly, coal.

Predictions of gas consumption through the 1980s vary widely, depending on market penetration assumptions, which are in themselves dependent on the volume of gas available and the price level at which that gas will be made available.

On the production side, the traditional sources of gas are going into decline, with the decline in production at Groningen by far the most important factor to be considered. Other areas in decline include the old German fields, the Lacq field in southwest France, Italian fields, and the U.K. southern North Sea.

For 1990, the range of estimates in shortfall of contracted supplies over demand is between 3 and 10 billion cubic feet per day, increasing rapidly through the 1990s. The gap will be filled by a mix of new North Sea production and imports, presumably from USSR, Algeria, and Nigeria. A major increase in import dependence will lead to heavy pressure to maximize North Sea production. This shortfall in continental European supplies provides the driving force for massive new investment in U.K. and Norwegian North Sea gas production, and, despite poorer intrinsic geological potential, also in Dutch, Danish, and German waters. This situation could lead to a much bigger role for gas investment in the North Sea than over the past 10 years.

An increasingly important feature of the gas markets, not apparent from average consumption data, is the growing varia-

tion between winter and summer demand. For instance, the 1980 average supply of 4.5 billion cubic feet per day in the U.K. necessitated swings of between 6.5 billion cubic feet per day in the winter and only 2.2 billion cubic feet in the summer. This load factor problem will worsen as the market shifts further towards the premium domestic market. As a result, in the U.K. at least, major investment is required in gas storage projects, and development of certain new fields, largely for winter production, is underway.

NORWEGIAN GAS RESERVES

Norway presents the most exciting potential source of new long-term supplies for the European markets. Norway has been exporting gas to both Europe and the U.K. since 1977, and the volume reached a total of 2.4 billion cubic feet per day this year. The existing gas sales contracts were based on reserves in the Ekofisk and Frigg fields which are now fully committed.

The potential for major increases in exports of Norwegian gas has therefore only arisen as a result of discoveries made in the last 2 years. A huge new gas province was discovered in 1980 east of the Statfjord field in the area around Block 31/2. The reserves appear to rank with the giant Groningen field, and in oil equivalent terms probably rank with Prudhoe Bay. It is difficult to overemphasize the long-term importance of these reserves to European buyers.

The existing pipeline infrastructure is inadequate both for the potential of the fields and the appetite of the markets. Norway has already announced and approved the Statpipe system, a major extension to the existing pipeline network from Ekofisk to Emden in West Germany. This system, costing some $2.1 billion, will be constructed in the first half of the decade, but will not tap the new reserves in the 31/2 area to any significant extent in the 1980s. Therefore, in the late 1980s or early 1990s it is probable that major additional investment in transportation infrastructure from the 31/2 area to Europe and/or the U.K. will be required.

U.K.

The U.K. is almost 100% dependent on North Sea gas production, and a substantial shortfall from existing fields is looming in the late 1980s. Given the extremely long lead times required to bring a North Sea discovery to production, positive action will be required in the near future to maintain gas share in the energy market. By the mid-1990s, the shortfall could exceed total current gas production capacity.

The recent collapse of the government's attempt to finance a new Gas Gathering System only serves to increase the urgency of the problem and shift focus on to industry-sponsored transportation systems and incentive gas pricing issues.

Despite the uncertainty over gas transportation, the sheer magnitude of the shortfall will require massive new investment in field development. Field investment will comfortably exceed the cost of new infrastructure required, and some $25 billion in total new gas project commitments could be necessary by 1990.

Steve McTiernan

WORLD OIL STOCKS

Last September, we published a summary of the estimated world oil stock position at the end of the third quarter of 1980. There was, at that time, an estimated 610 million barrels of oil surplus to normal needs, including oil stored for national "strategic" stockpiles.

Our current estimates are shown on the top of page 4. The surplus has fallen by 195 million barrels and the distribution changed significantly. Currently, there are over 180 million barrels of oil stored in floating storage.

REFINERY SPREADS

For nearly four years, we have been publishing the difference between crude cost and product revenue for two types of U.S. refinery. With this issue, we are extending this coverage to European and Japanese refineries.

Japanese Refineries

Two refinery types have been taken as representing high and low conversion appropriate to the actual capacity. In each case, the crude supplied is assumed to be of around 35° API gravity, with a delivered cost like that of an average Indonesian crude. The high and low conversion refinery yields assumed are shown here, with naphtha, because of its large significance in the market, shown separately. Prices are expressed in U.S. dollars.

	High Conversion	Low Conversion
Gasoline	18%	11%
Naphtha	17%	9%
Middle Distillate	30%	20%
Residual Fuel	35%	60%

Refinery Spreads – Japan – May 1981

		High Conversion		Low Conversion	
Product	Price $/BBL.	% Yield	Realization $/BBL	% Yield	Realization $/BBL
Gasoline	59.40	18	10.69	10	5.94
Naphtha	42.30	17	7.19	10	4.23
Middle Distillate	47	30	14.10	20	9.40
Residual Fuel	41	35	12.30	60	24.60
Product Realization			44.28		44.17
Crude Cost (Including taxes, etc.)			40.35		40.35
Spread			3.93		3.82

The margin increase between low- and high-conversion operations is minimal, and we understand that the pricing provisions may be changed to improve this. This relatively large margin reflects significantly greater operating costs in Japan relative to the U.S.

European Refineries

Two refinery types are also considered with yields based on a 350 crude, as shown here.

	High Conversion	Low Conversion
[illegible]	30%	10%
Naphtha	10%	10%
Middle Distillate	33%	25%
Residual Fuel	27%	55%
	100%	100%

Refinery Spreads – Europe – May 1981

		High Conversion		Low Conversion	
Product	Price $/Gal.	% Yield	Realization	% Yield	Realization
Gasoline	39.30	30	11.79	10	3.93
Naphtha	28.00	10	3.80	10	3.80
Middle Distillate	39.00	33	12.87	25	9.75
Residual Fuel	30.70	27	8.29	55	16.89
Product Realization			36.75		34.37
Crude Cost			36.50		36.50
Spread			0.25		– 2.13

The prices used are based on French, German, Italian, and British prices in equal proportions, using prevailing exchange rates. Naphtha prices are based on prevailing contract rates.

ESTIMATED CURRENT (END AUGUST '81) STOCK POSITION

(Million Barrels)

	United States				Rest of World				World
	Basic (1)	Seasonal	Surplus	Total	Basic (2)	Seasonal	Surplus	Total	Total
Producer	60	–	–	60	240	–	35	275	335
Loading Ports	40	–	20	60	460	–	35	495	555
Volume at Sea	25	–	10	35	615	–	110	725	760
Terminals	175	35	50	260	135	35	30	200	460
Refineries	700	65	100	865	1,500	100	10	1,610	2,475
Inland Distribution	180	30	10	220	320	40	5	365	585
Consumer Stocks	100	5	–	105	150	25	–	175	280
	1,280	135	190	1,605	3,420	200	225	3,845	5,450

(1) Includes an estimated 140 million barrels in strategic petroleum reserve.
(2) Includes an estimated 210 million barrels of "Strategic Reserve," 70 million at terminals, 40 million in ships and 100 million at refineries.

U.S. Refineries

The refiner acquisition cost of crude is taking longer to be developed by the Department of Energy and, hence, we include our estimates for the months of April to June.

U.S. Refiner Acquisition Cost of Crude ($/BBL)

	Feb. 1981	Mar. 1981	Apr. 1981	May 1981	June 1981
Imported	39.04	38.35	37.13	36.85	36.60
Domestic	36.40	36.95	36.20	35.50	35.00
Composite	37.36	37.48	36.48	35.93	35.51

The U.S. product prices for the six months, February to July, 1981 are shown here.

U.S. Average Wholesale Prices for Petroleum Products (Cents/Gallon)

	Feb.	March	April	May	June	July
Motor Gasoline	101.9	104.6	104.2	103.6	102.7	102.5
Kerosine	100.7	103.1	102.9	102.2	101.3	100.6
Distillate Fuel	97.3	100.4	100.1	99.5	98.2	97.7
Residual Fuel	65.0	64.9	64.8	64.4	60.7	59.1

These two price series lead to the refinery spread numbers in the following table.

	Type 1 Refinery	Type 2 Refinery
1975	1.21	0.10
1976	2.01	0.31
1977	2.49	0.94
1978	2.39	0.10
1979	4.19	0.84
1980	4.09	– 1.97
January, 1980	3.25	– 1.44
February, 1980	2.28	– 3.03
March, 1980	3.13	– 2.60
April, 1980	4.00	– 1.69
May, 1981	4.31	– 1.35
June, 1981	3.87	– 1.95

When the gross spread for the larger, high conversion refineries is considered, it must be remembered that fuel costs have increased by *over* $1.50 per barrel since 1979, and taking this into account, the average spread of $4.06 per barrel for the second quarter should be adjusted by this figure when comparing with the 1979 spread. The $4.06 spread becomes about $2.50 with this change, and if this is further adjusted for inflation, the figure in comparable dollars is well below the 1977 and 1978 numbers.

	AUGUST			3 MOS. AVERAGE			YEAR TO DATE AVERAGE		
	1981	1980	Change	1981	1980	Change	1981	1980	Change
	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –
PRIMARY DEMAND									
Motor Gasoline	6,767	6,841	– 1.1	6,771	6,926	– 2.2	6,535	6,908	– 5.4
(Unleaded)*	3,568	3,203	11.4	3,590	3,132	14.6	3,321	3,012	10.2
Jet Fuel	998	1,043	– 4.3	1,027	1,070	– 4.0	1,018	1,077	– 5.5
Kerosine	90	138	– 34.8	102	124	– 27.8	128	159	– 19.6
Distillate Fuel	2,412	2,256	6.9	2,373	2,326	2.0	2,814	2,890	– 2.6
Residual Fuel	2,128	2,348	– 9.4	2,040	2,348	– 13.1	2,158	2,572	– 16.1
All Other	3,266	3,115	4.8	3,233	3,184	1.5	3,305	3,286	0.6
Total Domestic Demand	15,661	15,741	– 0.5	15,547	15,979	– 2.7	15,958	16,892	– 5.5
Exports	535	319	67.7	550	499	10.1	538	521	3.1
Total Demand	16,196	16,060	0.8	16,096	16,478	– 2.3	16,496	17,413	– 5.3
New Supply									
Domestic	10,878	10,721	1.5	10,757	10,809	– 0.5	10,857	10,830	0.3
Crude Oil	8,639	8,422	2.6	8,633	8,508	1.5	8,583	8,612	– 0.3
Natural Gas Liquids	1,559	1,514	3.0	1,547	1,528	1.2	1,571	1,578	– 0.5
Other Supply	680	785	– 13.4	577	773	– 25.3	703	639	10.0
Imports	5,443	6,102	– 10.8	5,362	6,341	– 15.5	5,717	7,025	– 18.6
Crude Oil	3,861	4,723	– 18.3	3,938	4,944	– 20.3	4,229	5,438	– 22.2
Refined Products	1,582	1,379	14.7	1,423	1,398	1.8	1,488	1,587	– 6.2
Residual Fuel	830	875	– 5.1	720	804	– 10.4	766	900	– 14.9
All Other	752	504	49.2	703	594	18.4	722	687	5.2
Total New Supply	16,321	16,823	– 3.0	16,119	17,150	– 6.0	16,574	17,854	– 7.2
Crude Oil Refined	12,988	13,011	– 0.2	12,722	13,318	– 4.5	12,655	13,558	– 6.7
Stock Change	125	763	–	23	672	–	78	441	–
Stocks – End of Month in Million Barrels									
Gasoline	240	259	– 7.5						
Jet Fuel	45	40	11.3						
Kerosine	14	13	2.0						
Distillate Fuel	206	226	– 9.0						
Residual Fuel	74	87	– 14.5						
All Other	339	344	– 1.5						
Total Products	917	970	– 5.5						
Crude Oil	374	388	– 3.6						
Total – All Oils	1,291	1,358	– 4.9						

Totals may not add due to rounding
*Included in motor gasoline

Sources: *American Petroleum Institute*
Chase Manhattan Bank
Department of Energy

Petroleum Industry Investments in the Eighties

This report provides an in-depth analysis of the non-Communist petroleum industry's expected capital expenditures and financial performance through 1990. Based on an assessment of the world's need for conventional hydrocarbons, projections are presented of the investments required in exploration and production by region, as well as refining, petrochemicals, transportation, marketing, and other areas. The petroleum industry's credit market requirements are forecast for the world outside Communist areas after which the study focuses on the U.S. petroleum industry's projected source and use of funds. The study concludes with a discussion of the sensitivity of U.S. petroleum industry capital expenditures to crude oil prices.

Below, we provide the Table of Contents of the study. The study is available at $50 (U.S.), payable by check or money order, to The Chase Manhattan Bank, N.A.

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World Coal Outlook to the Year 2000: Opportunities and Uncertainties

This 50-page report on the outlook for coal includes detailed regional forecasts of coal demand by end-use application. In addition, regional coal production forecasts are provided, with a detailed analysis of regional coal trade patterns. The assessment of coal trade includes a separate analysis of trade in metallurgical and thermal coals. The study concludes with an analysis of the level of seaborne coal trade and the availability of ports to support projected levels of international trade. "World Coal Outlook to the Year 2000" is available for $75.

ALTHOUGH SEPARATELY THE COST OF THESE THREE REPORTS WOULD COME TO $225, THE ENERGY ECONOMICS DIVISION IS MAKING ALL THREE AVAILABLE AT A PACKAGE PRICE OF $175. IF YOU WOULD LIKE ALL THREE STUDIES, PLEASE INDICATE THIS ON THE ORDER BLANK BELOW.

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CHASE MANHATTAN BANK OFFERS THREE NEW ENERGY-RELATED PUBLICATIONS

- **The World Energy Outlook Through 2000: A Time of Transition**
- **Petroleum Industry Investments in the Eighties**
- **World Coal Outlook to the Year 2000: Opportunities and Uncertainties**

Chase energy forecasts are unique in that they have been developed simultaneously with a set of financial forecasts of the key energy industries. For example, the oil and gas production forecasts for the U.S. have been tested for financial feasibility in terms of both cash flow and ROI. The forecasts are a blend of judgment and mathematical analysis developed via a family of large-scale, computerized simulation models.

The World Energy Outlook Through 2000

This 100-page report provides, in detail, a forecast of regional energy demands by fuel type based on a careful assessment of potential supplies of conventional sources of energy as well as unconventional ones such as solar and nuclear fusion. Because oil is expected to remain the energy choice on the margin, the focal point of the analysis was the determination of the feasibility of the crude oil production required from the Persian Gulf states (the so-called swing producers), given our OPEC oil price assumption and, after all other liquid sources, conventional and synthetic, were taken into account. The revenues received by the Persian Gulf producers under our assumed price and production scenario were then validated against a Chase estimate of "minimum desired revenues," that is, those revenues sufficient to sustain minimum desired internal growth objectives as well as foreign investments without implying a build-up of foreign debt. A given set of energy price, supply and demand projections was accepted as the best estimate forecast only when the estimated realized revenue levels were consistent with the minimum desired revenue estimates. After a careful discussion of our best estimate energy price, supply, and demand forecasts, the study concludes with a look at the uncertainties surrounding the estimation of the key determinant of future energy demand, namely OPEC oil prices.

Below, we provide the Table of Contents of the study, which indicates the specific topics under discussion. The study is available at $100 (U.S.), payable by check or money order, to The Chase Manhattan Bank, N.A.

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The Petroleum Situation

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1980– Financial Analysis of a Group of Petroleum Companies

Please note that starting with this issue, the Financial Analysis of a Group of Petroleum Companies will be published annually in a special issue of the Petroleum Situation instead of in the traditional booklet form.

Operations

Source of Crude Oil

Higher prices and an economic slowdown reduced the overall non-Communist world demand for crude oil and products in 1980. Consequently, as shown below, the Group's supply of crude oil from equity production and purchases from governments of oil producing countries declined on an average daily basis by 3.7 million barrels, to 23.8 million barrels. As a proportion of all the crude oil produced in the non-Communist world in 1980, the Group's volume represents approximately 53 percent, down from 56 percent a year earlier and 61 percent two years ago.

In 1980, as shown in the table below, in crude supplies from Canada, Other Western Hemisphere, Africa, the Middle East, and the Far East more than offset increases which were registered in the United States and Europe.

SOURCE OF CRUDE OIL

	1980	1979	Percent Change
	Thousand Barrels Per Day		
United States	6,071	5,944	2.1
Canada	1,044	1,145	(8.8)
Other Western Hemisphere*	1,227	1,459	(15.9)
Western Hemisphere	8,342	8,548	(2.4)
Europe	1,710	1,627	5.1
Africa	2,235	2,671	(16.3)
Middle East	10,148	13,256	(23.4)
Far East	1,366	1,433	(4.7)
Eastern Hemisphere	15,459	18,987	(18.6)
Total	23,801	27,535	(13.6)

Note: The above figures include 100% of operations of companies and consolidated subsidiaries and equity in foreign operations of non-consolidated affiliates based on percentage of stock ownership, plus purchases from governments.
*Includes Venezuela at 653 TBD in 1980 and 992 TBD in 1979.

By far the most significant reduction occurred in the Middle East, where the Group's supply dropped by 3.1 million barrels per day to 10.1 million. In spite of this large decline, the Middle East continued as the foremost supply source of crude oil for the Group, providing 43 percent of the overall volume in 1980. Its share, however, was down from 48 percent the year before.

Crude Runs to Refineries

The reduced consumption of petroleum products caused the Group to reduce refinery runs in 1980 by 2.8 million barrels of crude oil per day to an average of 24.7 million barrels daily, as shown in the table below. At that level, the Group accounted for 53 percent of total refinery throughput in the non-Communist areas of the world, down from 56 percent in 1979. The largest declines were in Europe at 1.3 million barrels a day, followed by the United States with a drop of nearly one million barrels per day. Together, those two areas accounted for 80 percent of the Group's reduction in crude runs in 1980.

CRUDE RUNS TO REFINERIES

	1980	1979	Percent Change
	Thousand Barrels Per Day		
United States	10,874	11,847	(8.2)
Canada	1,559	1,621	(3.8)
Other Western Hemisphere	1,585	1,639	(3.3)
Western Hemisphere	14,018	15,107	(7.2)
Europe	7,450	8,703	(14.4)
Africa	317	307	3.3
Middle East	269	468	(42.5)
Far East	2,638	2,896	(8.9)
Eastern Hemisphere	10,674	12,374	(13.7)
Total	24,692	27,481	(10.1)

Note: The above figures include 100% of operations of companies and consolidated subsidiaries and equity in foreign operations of non-consolidated affiliates based on percentage of stock ownership.

Companies Included in Study

Amerada Hess Corporation
Ashland Oil, Inc.
Atlantic Richfield Company
The British Petroleum Company Limited
Champlin Petroleum Company
Cities Service Company
Clark Oil & Refining Corporation
Compagnie Francaise des Petroles
Conoco, a Sub. of DuPont
Exxon Corporation
Getty Oil Company
Gulf Oil Corporation
The Louisiana Land and Exploration Company
Marathon Oil Company
Mobil Oil Corporation
Murphy Oil Corporation
Petrofina Societe Anonyme
Phillips Petroleum Company
Royal Dutch/Shell Group of Companies
Standard Oil Company of California
Standard Oil Company (Indiana)
Sun Company, Inc.
The Superior Oil Company
Texaco Inc.
Tosco Corporation
Union Oil Company of California

Income Statement

Revenue

In 1980, the Group recorded significant increases in both revenue and costs, principally because of higher prices worldwide for crude oil and products.

The following table compares the Group's income statement for 1980 and 1979.

INCOME STATEMENT

	1980	1979	Percent Change
	Million Dollars		
Gross Operating Revenue	590,536	455,023	29.8
Non-Operating Revenue	12,337	8,426	46.4
Total Revenue	602,873	463,449	30.1
Operating Costs and Expenses	461,508	347,003	33.0
Taxes Other Than Income Taxes (a)	24,611	15,456	59.2
Write-Offs	22,659	19,089	18.7
Interest Expense and Other Charges	6,047	5,356	12.9
Total Deductions	514,825	386,904	33.1
Net Income before Income Taxes	88,048	76,545	15.0
Estimated Income Taxes	50,301	42,732	17.7
Income Applicable to Minority Interests	2,557	2,335	9.5
Net Income (b) (c)	35,190	31,478	11.8

(a) Excludes $54,055 million in 1980 and $48,832 million in 1979 of consumers sales and excise taxes on gasoline and other refined products. These taxes are deducted before arriving at gross operating revenue.

(b) Excludes $417 million of extraordinary profit in 1980 and $316 million in 1979.

(c) Includes earnings from operations outside U.S.: $19,556 million in 1980 and $18,720 million in 1979.

Rising by $135.5 billion, gross operating revenue totaled $590.5 billion, nearly 30 percent more than in 1979. The revenue shown below generated from the sale of crude oil and refined products – $498.4 billion – increased by $120 billion and accounted for 84.4 percent of the total. Proceeds from chemical products, representing 6.6 percent of the revenue, rose by $4 billion to a level of $38.8 billion. Revenue from natural gas – $23 billion – amounted to only 3.9 percent of the total. Thus, although natural gas is a major source of energy, it continues to be a minor source of revenue since natural gas net back prices are still relatively low compared to oil. The Group also received $30.3 billion in revenue from a variety of other operating activities.

Non-operating revenue, primarily from interest, dividends, and equity in the earnings of affiliated companies, provided another $12.3 billion, bringing the Group's total revenue to $602.9 billion in 1980, as indicated in the table above.

Charges Against Revenue

Although the Group's revenue grew by 30 percent, in total the various expenses charged against revenue rose more than 31 percent. The largest expense category, operating costs and expenses, increased substantially by 33 percent to $461.5 billion. The predominant factor causing the large increase was the higher cost of purchased crude oil in 1980.

Taxes other than income taxes surged by a record $9.2 billion to $24.6 billion. This extraordinary increase resulted principally from the impact of the U.S. federal excise tax or "Windfall Profits Tax" imposed on the petroleum industry which became effective March 1, 1980. Income taxes also continued on the upswing, rising to $50.3 billion from $42.7 billion the year before. In total, therefore, taxes rose by $16.7 billion to a sum of $74.9 billion. Compared to earnings, that tax bill is equivalent to more than twice the Group's net income in 1980. Not included in the reported taxes are consumer sales and excise taxes. Because these taxes are imposed on the consumer, and the Group acts only as a collecting agent for government, they are omitted from both the revenue and tax figures in this study.

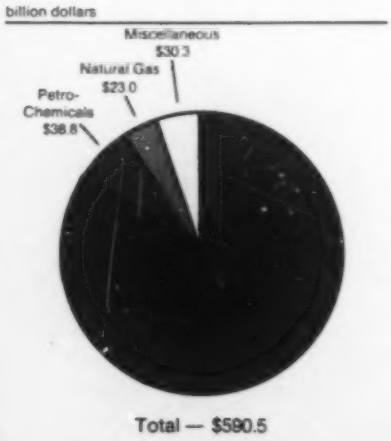
As a consequence of the substantial growth in capital investments, write-offs for depreciation, depletion, amortization, and other recovery of capital, provisions totaled $22.7 billion, $3.6 billion more than in 1979.

Despite larger borrowings and higher interest rates, the increase in interest expense from $5.4 billion the year before to $6.0 billion in 1980 was more moderate than the increases registered by most of the other expense items. This was in part due to a change in accounting standards that required capitalization of interest costs on major capital projects. This change reduced the amount of interest expense that would have otherwise been recorded.

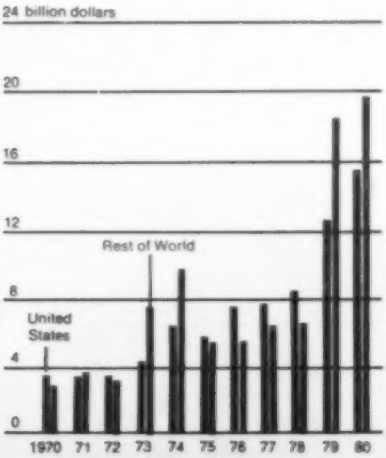
Net Income

Net income totaled $35.2 billion, an increase of $3.7 billion or 11.8 percent over 1979. Not only was the Group's earnings improvement of 11.8 percent considerably smaller than the 110 percent increase recorded in 1979, but the source of the improved results contrasted sharply with the prior year. Nearly three-quarters of the profit gain in 1979 occurred outside the United States, while 77 percent of the 1980 increase was generated in the United States. Nevertheless, the Group's overall net income continued to be greater outside the United States – $19.6 billion vs. 15.6 billion.

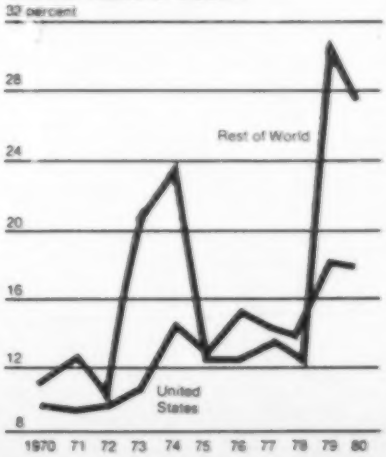
SOURCES OF REVENUE — 1980



NET INCOME



RETURN ON AVERAGE SHAREHOLDERS' EQUITY



Rate of Return

With investment growing at a greater rate than net income in 1980, the Group's rate of return on average shareholders' equity declined to 22.4 percent from 24 percent in 1979. As shown in the table at right, even in the United States, where most of the earnings gain occurred, the return on average net assets dropped slightly from the 1979 rate of 18.2 percent to 18.1. In the rest of the non-Communist world, the Group's rate of return on average net assets fell by more than three percentage points, to 27.7 percent from a level of 30.8. The table lists various rates of return earned by the Group in 1980 as well as 1979.

RATES OF RETURN

	Percent Return	
	1980	1979
On Average Shareholders' Equity	22.4	24.0
On Average Net Assets – U.S.	18.1	18.2
On Average Net Assets – Outside U.S.	27.7	30.8
On Average Capital Employed (a)	20.6	21.6
On Average Total Assets (b)	10.2	11.0

(a) The return on average capital employed is computed by dividing net income plus interest charges, plus income applicable to minority interests by average long-term debt, preferred stock, common stock, surplus, and equity of minority interests.

(b) The return on average total assets is computed by dividing net income plus income applicable to minority interests by average total assets.

Source and Use of Funds

Sources

Internal sources from operations provided $66.8 billion or 78.7 percent of the Group's capital needs, as indicated in the table below. This was up slightly from 78.2 percent the year before. The sale of assets provided another $6 billion or 7.2 percent.

The balance of the Group's funding requirements of about $12 billion came from external sources. The bulk of that $12 billion – $11.4 billion – represents capital borrowed on a long-term basis. This was the largest amount of long-term debt ever issued by the Group in a single year. The components of the Group's 1980 funds flow statement are presented in the following table.

1980 SOURCE AND USE OF FUNDS

	Million Dollars	Percent Distribution
Source of Funds:		
Net Income	35,190	41.4
Write-Offs	22,659	26.7
Other Non-Cash Charges (net)	8,985	10.6
Total Cash Earnings	66,834	78.7
Long-Term Debt Issued	11,378	13.4
Preferred and Common Stock Issued	580	0.7
Sales of Assets and Other Transactions	6,078	7.2
Total	84,870	100.0
Use of Funds:		
Capital Expenditures	55,606	65.5
Investments and Advances	2,619	3.1
Dividends to Companies' Shareholders	10,018	11.8
Dividends to Minority Interests	544	0.6
Long-Term Debt Repaid	8,791	10.4
Preferred and Common Stock Retired	990	1.2
Total	78,568	92.6
Change in Working Capital	+6,302	7.4

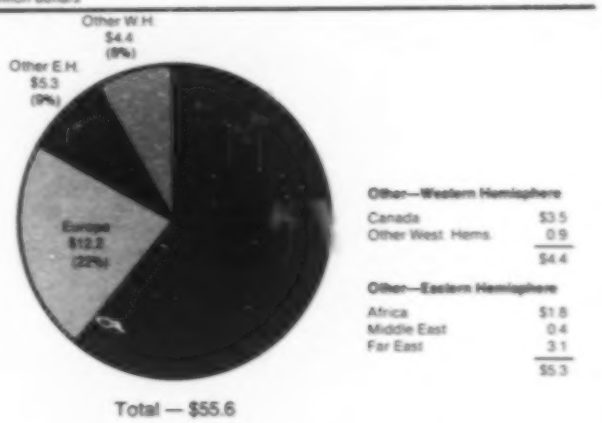
Uses

Capital Expenditures

Following an unprecedented $13.9 billion increase in capital expenditures the year before, the Group's investments in 1980 rose by $11.8 billion, to $55.6 billion, the second highest year-to-year increase on record. During the five-year period, 1973 to 1978, the Group's capital investment doubled, from $14.6 billion to $29.9 billion. In just the past two years, however, keeping pace with net income growth, capital expenditures have almost doubled once again, from the 1978 level of $29.9 billion to $55.6 billion in 1980. This translation of earnings into increased investment reflects the positive way the industry responds to higher rate of return incentives.

CAPITAL EXPENDITURES — BY AREA
1980

billion dollars



Total — $55.6

As shown in the figure above, geographically, 61 percent of the Group's worldwide capital expenditures in 1980 was located in the United States. The capital invested for production purposes accounted for 68 percent of all investments in the United States and 64 percent in the rest of the world. The funds allocated for processing facilities (refineries and chemical plants) ran a very distant second both outside and within the United States. A detailed breakdown of the Group's 1980 capital expenditures for the United States and the rest of the world is presented in the next table.

1980 CAPITAL AND EXPLORATION EXPENDITURES

By Function	United States	Other Countries
	Million Dollars	
Production:		
Production Expenditures	20,321	11,989
Dry Holes	2,130	1,877
Total Crude Oil and Natural Gas	22,451	13,866
Natural Gas Liquids Plants	583	115
Total Production	23,034	13,981
Transportation:		
Pipe Lines	717	61
Marine	484	732
Other	396	15
Total	1,597	808
Refineries and Chemical Plants	4,789	3,495
Marketing	1,121	2,150
Others	3,184	1,447
Total Capital Expenditures	33,725	21,881
Geological and Geophysical Expenses and Lease Rentals	2,602	1,766
Total Capital and Exploration Expenditures	36,327	23,647

Balance Sheet

Working Capital

Except for a slight decrease in cash, as indicated in the table below, all other components of current assets and current liabilities increased in 1980. The increased cost of crude oil and higher product prices plus increased financing costs and taxes were the principal factors affecting working capital.

The value of total inventories rose by $10.1 billion or 20.7 percent to $58.9 billion, and accounts and notes receivable also grew substantially by $6.5 billion to $69.1 billion. Together, these items accounted for more than three-quarters of the 14.5 percent increase in current assets.

Current liabilities at the end of 1980 were 13.7 percent above those of a year earlier. But, because current assets grew at a rate of 14.5 percent, the Group's current ratio rose slightly to 1.36 from 1.35 in 1979. Collectively, the changes in current assets and current liabilities resulted in an increase of $6.3 billion in working capital.

BALANCE SHEET

Assets	12/31/80	12/31/79	Percent Change
	Million Dollars		
Cash	15,661	15,848	(1.2)
Marketable Securities	17,973	14,886	20.7
Accounts and Notes Receivable (net)	69,096	62,619	10.3
Inventories:			
Crude Oil, Refined Products and Other Merchandise	52,869	44,191	19.6
Materials and Supplies	5,985	4,551	31.5
All Other	4,197	2,669	57.2
Total Current Assets	165,781	144,764	14.5
Investments and Advances	18,795	15,765	19.2
Property, Plant and Equipment (a)	206,610	173,646	19.0
Other Assets	8,407	6,362	32.1
Total Assets	399,593	340,537	17.3
Liabilities and Shareholders' Equity			
Accounts Payable	66,664	64,354	3.6
Notes and Loans Payable	16,988	12,690	33.9
Income and Other Taxes	25,735	20,218	27.3
All Other	12,946	10,356	25.0
Total Current Liabilities	122,333	107,618	13.7
Long-Term Debt	46,997	43,397	8.3
Deferred Credits	34,837	24,934	39.7
Other Reserves	13,361	11,327	18.0
Minority Interests	11,802	9,338	26.4
Shareholders Equity:			
Preferred Stock	366	220	66.4
Common Stock	12,614	12,526	0.7
Retained Earnings & Capital Surplus	157,283	131,177	19.9
Total Shareholders' Equity	170,263	143,923	18.3
Total Liabilities and Shareholders' Equity	399,593	340,537	17.3
Working Capital	43,448	37,146	17.0
Ratio of C.A. to C.L.	1.36	1.35	–

(a) After deducting accumulated reserves of $122,732 million in 1980 and $108,624 million in 1979.

The Group's total capital employed, comprising long-term debt, minority interests, and shareholders' equity, was $229.1 billion at the end of 1980, 16.5 percent higher than at the close of the previous year. Shareholders' equity rose by 18.3 percent to $170.3 billion, and minority interests registered a gain of 26.4 percent to $11.8 billion. The rate of increase in long-term debt was only 8.3 percent. Consequently, the long-term debt proportion of capital employed was down to 20.5 percent from 22.1 percent in 1979.

Property, Plant and Equipment

At the close of 1980, as shown in the table below, the Group had a combined net investment in property, plant and equipment of $206.6 billion after deducting the accumulated charges for depreciation, depletion, and amortization. Of that amount, the heaviest concentrations were located in the United States with 60 percent, and Europe with 24 percent. On a functional basis, 51 percent was allocated for production, 22 percent for refineries and chemical plants, 10 percent for transportation, 9 percent for marketing and 8 percent for other miscellaneous activities.

INVESTMENT IN FIXED ASSETS
DECEMBER 31, 1980

By Function –	Gross			Net		
	United States	Other Countries	Combined	United States	Other Countries	Combined
	Million Dollars			Million Dollars		
Production:						
Crude Oil and Natural Gas	105,890	54,554	160,444	62,380	39,804	102,184
Natural Gas Liquids Plants	4,038	2,038	6,076	1,972	1,224	3,196
Total	109,928	56,592	166,520	64,352	41,028	105,380
Transportation:						
Pipe Lines	13,861	836	14,697	10,113	439	10,552
Marine	2,860	11,526	14,386	1,953	7,246	9,199
Other	2,959	431	3,390	1,701	257	1,958
Total	19,680	12,793	32,473	13,767	7,942	21,709
Refineries and Chemical Plants	44,308	33,191	77,499	27,136	18,216	45,352
Marketing	12,314	19,761	32,075	7,542	10,862	18,404
Others	14,756	6,019	20,775	11,219	4,546	15,765
Total	200,986	128,356	329,342	124,016	82,594	206,610

By Area –	12/31/80		Change from 1979	
	Gross	Net	Gross	Net
	Million Dollars		Percent	
United States	200,986	124,016	16.9	19.1
Canada	21,995	14,904	15.7	17.5
Other Western Hemisphere	6,634	3,518	19.5	22.7
Western Hemisphere	229,615	142,438	16.9	19.0
Europe	76,965	50,268	14.9	17.3
Africa	8,372	5,128	24.5	30.5
Middle East	2,304	1,000	(1.1)	(10.6)
Far East	12,086	7,776	23.7	27.9
Eastern Hemisphere	99,727	64,172	16.2	18.9
Total	329,342	206,610	16.7	19.0

Patrick J. Keenan
Richard S. Dobias
Norma J. Anderson

Historical Data

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Income Statement						Million Dollars						
Total Revenue	77,947	86,125	97,860	106,278	133,909	244,535	245,204	275,908	317,520	346,880	463,449	602,873
Deductions:												
Operating Costs and Other Expenses	56,784	62,615	70,690	76,465	92,756	178,438	185,707	217,800	252,068	276,456	354,694	470,112
Taxes Other Than Income Taxes	3,610	4,473	4,413	5,138	6,241	7,214	9,137	8,516	9,986	11,841	15,456	24,611
Write-offs	6,084	6,636	7,079	7,514	8,345	10,133	11,187	11,230	12,982	15,570	19,089	22,659
Income Taxes	4,767	5,763	8,409	10,301	14,889	32,379	27,663	25,263	28,104	27,996	42,732	50,301
Total Deductions	71,245	79,487	90,591	99,418	122,231	228,164	233,694	262,809	303,140	331,863	431,971	567,683
Net Income – Worldwide	6,702	6,638	7,269	6,860	11,678	16,371	11,510	13,099	14,380	15,017	31,478	35,190
United States	3,774	3,609	3,490	3,656	4,134	6,401	5,978	7,535	7,795	8,336	12,758	15,634
Rest of World	2,928	3,029	3,779	3,204	7,544	9,970	5,532	5,564	6,585	6,681	18,720	19,556
Rates of Return						Percent						
Average Shareholders' Equity	11.0	10.4	10.7	9.7	15.5	19.2	12.8	13.8	13.8	13.2	24.0	22.4
Average Net Assets – U.S.	10.9	9.9	9.3	9.6	10.5	14.6	12.9	15.2	14.2	13.8	18.2	18.1
Average Net Assets – Outside U.S.	11.2	11.0	12.5	9.9	20.9	23.9	12.7	12.3	13.4	12.5	30.8	27.7
Average Capital Employed	10.4	9.9	10.1	9.4	14.0	17.3	12.0	12.9	13.0	13.1	21.6	20.6
Average Total Assets	6.8	6.2	6.3	5.5	8.6	10.0	6.1	6.6	6.4	6.1	11.0	10.2
Source and Use of Funds												
Source of Funds:						Million Dollars						
Cash Earnings (a)	13,482	13,823	14,775	14,801	21,230	28,836	23,570	26,767	29,964	34,322	57,456	66,834
Long-Term Debt and Stock Issued	3,801	4,571	5,163	4,698	4,813	6,394	10,305	10,526	8,768	5,241	8,802	11,958
Sale of Assets and Other Transactions	788	1,067	885	1,860	2,867	4,372	1,167	2,713	4,415	5,252	7,177	6,078
Total	18,071	19,461	20,823	21,359	28,910	39,602	35,042	40,006	43,147	44,815	73,435	84,870
Use of Funds:												
Capital Expenditures	11,560	12,025	12,921	13,190	14,637	22,902	25,048	26,826	28,001	29,893	43,812	55,606
Investments and Advances	1,289	804	992	763	382	914	1,744	832	1,523	1,567	2,495	2,619
Dividends	3,730	3,790	3,922	3,860	4,122	4,772	4,947	5,346	6,158	6,953	8,333	10,562
Long-Term Debt and Stock Retired	2,305	2,191	2,100	3,330	4,268	4,226	5,435	5,313	6,053	7,081	8,374	9,781
Total	18,884	18,810	19,935	21,143	23,409	32,814	37,174	38,317	41,735	45,494	63,014	78,568
Change in Working Capital	– 813	+ 651	+ 888	+ 216	+5,501	+6,788	–2,132	+1,689	+1,412	– 679	+10,421	+ 6,302

(a) Represents Net Income, Writeoffs and Other Non-Cash Charges.

Capital Expenditures												
United States:						Million Dollars						
Crude Oil and Natural Gas (a)	3,399	2,821	2,510	3,842	4,729	8,142	6,205	7,708	8,762	10,066	18,799	22,451
Natural Gas Liquids Plants	198	189	156	115	120	183	243	251	238	287	358	583
Pipe Lines	146	292	275	193	240	1,282	3,300	3,327	1,537	338	337	717
Marine	96	79	97	58	86	73	144	190	444	182	285	484
Other Transportation	64	56	76	53	63	74	85	148	128	234	316	396
Refineries and Chemical Plants	1,368	1,509	1,430	1,212	1,269	2,382	3,014	3,659	3,328	3,395	3,941	4,789
Marketing	1,138	1,319	1,322	1,001	744	541	574	512	650	740	823	1,121
Other	338	372	399	337	350	733	845	869	1,534	1,561	2,265	3,184
Total	6,747	6,637	6,265	6,811	7,601	13,410	14,410	16,664	16,621	16,803	27,124	33,725
Rest of World:												
Crude Oil and Natural Gas (a)	1,633	1,578	1,917	2,088	2,564	4,576	5,957	6,265	6,935	8,012	10,597	13,866
Natural Gas Liquids Plants	147	187	175	114	76	139	132	196	304	237	71	115
Pipe Lines	65	53	151	118	90	85	73	22	48	48	27	61
Marine	513	502	735	826	1,463	1,672	1,319	883	679	319	519	732
Other Transportation	4	3	7	6	9	13	25	8	5	15	79	15
Refineries and Chemical Plants	1,340	1,673	2,180	1,819	1,573	1,895	1,957	1,646	1,864	2,311	2,672	3,495
Marketing	1,018	1,194	1,348	1,222	1,079	947	891	921	1,106	1,457	1,692	2,150
Other	93	198	143	186	182	165	284	221	439	691	1,031	1,447
Total	4,813	5,388	6,656	6,379	7,036	9,492	10,638	10,162	11,380	13,090	16,688	21,881

(a) Excludes exploration expenses and lease rentals charged to income account.

Balance Sheet												
						Million Dollars						
Current Assets	33,506	36,501	39,586	42,686	56,149	86,889	84,361	92,598	99,149	107,416	144,764	165,781
Property, Plant and Equipment (Net)	62,179	66,703	71,740	75,097	79,613	91,169	99,027	110,493	128,555	147,147	173,646	206,610
Other Assets	10,943	11,763	13,573	14,400	14,654	15,189	18,178	19,056	21,044	20,727	22,127	27,202
Total Assets	106,628	114,967	124,899	132,183	150,416	193,247	201,566	222,147	248,748	275,290	340,537	399,593
Current Liabilities	21,115	23,459	25,656	28,540	36,502	60,454	60,058	66,606	71,745	80,691	107,618	122,333
Long-Term Debt	15,597	17,742	20,523	21,858	22,727	25,591	30,645	36,249	39,914	40,645	43,397	46,997
Other Liabilities	4,765	5,145	5,882	6,998	8,532	11,394	13,989	16,671	22,414	28,499	36,261	48,198
Minority Interests	2,689	2,845	2,941	3,031	3,274	4,068	3,701	3,916	4,676	7,035	9,338	11,802
Shareholders' Equity	62,462	65,776	69,897	71,756	79,381	91,740	93,173	98,705	109,999	118,420	143,923	170,263
Total Liabilities & Shareholders' Equity	106,628	114,967	124,899	132,183	150,416	193,247	201,566	222,147	248,748	275,290	340,537	399,593
Working Capital	12,391	13,042	13,930	14,146	19,647	26,435	24,303	25,992	27,404	26,725	37,146	43,448

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The Petroleum Situation

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AN OFFSHORE LEASING PROGRAM THAT MAKES SENSE

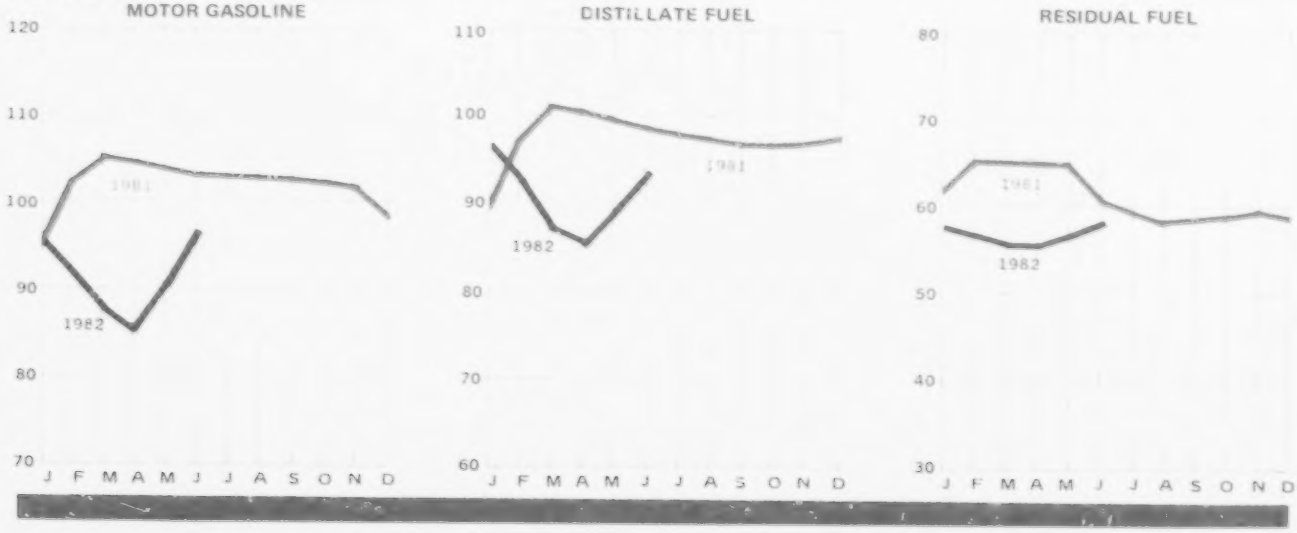
In a previous issue of the Petroleum Situation (Vol. 3, No. 12 – December, 1979), we expressed concern that U.S. energy development was being unnecessarily hindered by a restrictive leasing policy for the Outer Continental Shelf (OCS). While much of the public criticism at that time was directed at the government onshore leasing policy, the offshore was estimated by Chase to be capable of yielding at least an additional 500,000 barrels per day by 1990 if a more expansive leasing policy were followed.

The emphasis of the Department of the Interior under the previous administration was on a program that, utilizing the Department of Energy's computer program, would "maximize" the benefit of the leasing program. This maximization was subject to a series of constraints, some 15 in all, that included the time required to develop each sale, environmental studies necessary, weather, capital availability, rig availability, and manpower availability. Although the net benefit to the nation was purportedly maximized, one was left wondering whether achieving the maximum revenue to the government was not, in fact, the goal.

Events of the last decade, if they have done nothing else, have served to show the fallible nature of expert judgment in almost all aspects of the oil market, including the supply response to changing price. Rig availability in the U.S. was thought by many to be a significant constraint in 1979. The huge run-up in active rigs through 1981 was much greater than most analysts anticipated and cast doubts on the necessity of a rig availability constraint. Similar points can be made with respect to most of the constraints considered at that time by the Department of Energy. It is our view that market determination will, in most cases, develop the optimum decisions and that assumed constraints on the interplay of market forces will lead to inefficiencies. This is particularly the case for the offshore leasing program. The potential of the OCS is great, and even under the previous leasing program oil production was projected to rise by some 400 to 600 thousand barrels per day by 1990.

Secretary of the Interior James Watt has announced a new leasing program that will make available more than one billion acres over the next five years. This proposal includes "area wide" lease offerings in which entire regions are being made available for lease. Examples include the Western Gulf of Mexico, at 35 million acres, Central and Northern California (one region) at 37 million acres, and the Diapir Field in the Beaufort Sea at 49 million acres. The first such sale will be the Central Gulf of Mexico, sale number 72, scheduled for May, 1983 and covering 46 million acres. This sale is due to have a draft environmental impact statement presented in August, 1982.

U.S. Wholesale Prices . . .
BY MONTHS
cents per gallon



The program proposed is large, includes areas of prime interest to industry, and is being pushed as rapidly as procedures will allow. By the completion of the schedule in 1987, the bulk of the OCS will have been offered for leasing, which is going to have a marked effect on the development of the OCS resources. In this article, after reviewing how the U.S. leasing program will change, we make an estimate of the bottom line—how much more oil and gas the new program will yield, and its effect on balance of payments and government lease bonus revenues.

Table A summarizes the OCS lease sale experience over the last eight years.

TABLE A

1974-1981 LEASE SALE EXPERIENCE

Year	No. of Sales	Acres Offered (Thousands)	Acres Leased (Thousands)	Bonus Paid (Million $)	Average Per Acre ($)	Range Per Acre ($)
1974	5	5006.9	1762.2	5022.8	2850.3	25 – 4968
1975	4	7247.3	1679.9	1088.1	647.7	438 – 1346
1976	4	2827.4	1278.0	2242.8	1754.9	1091 – 1238
1977	2	1843.1	1100.7	1568.6	1425.1	804 – 1933
1978	4	3140.7	1297.3	1767.1	1362.1	304 – 2113
1979	6	3412.2	1767.5	5078.8	2873.4	180 – 5800
1980	3	2563.5	1134.3	4204.7	3706.9	551 – 4853
1981	7	7679.7	2231.4	6820.1	3056.4	30 – 3774

In terms of geographic areas, the leases offered and taken are covered in Table B.

Past bidding provides a basis for estimating future bids. On average, 4.2 million acres per year were offered between 1974 and 1981, and 1.5 million acres leased. The average acreage being offered in the next five years is over 200 million per year, approximately half of which will be in Alaskan waters. In the 1974-1981 period, Gulf of Mexico leases represented nearly 63 percent of the total. In the next five years, offered tracts in the Gulf of Mexico will represent about 14 percent of the total acreage. Despite this, Gulf of Mexico acreage offered will be nearly seven times the total area offered there in the previous eight years.

TABLE B

LEASES OFFERED AND TAKEN BY REGION

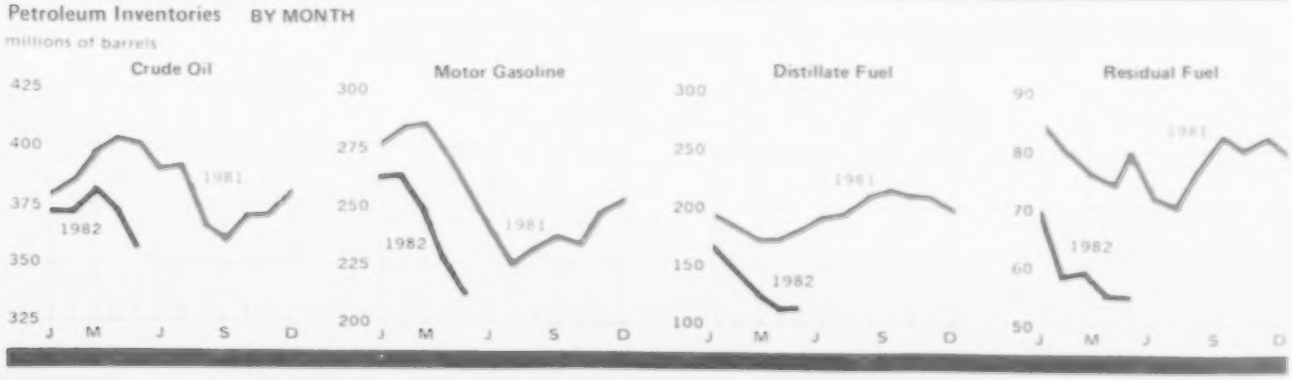
Region	No. of Sales	Sale Years	Acres Offered (Thousands)	Acres Taken (Thousands)	Bonus (Million $)	Bonus ($) Per Acre
Alaska	4	76, 79, 80 81	3,372.7	699.9	1,158.5	1,655
Atlantic	6	76, 78, 79 81	6,595.4	1,907.2	2,749.9	1,442
California	3	75, 79, 81	2,654.0	890.4	3,247.7	3,647
Gulf of Mexico	22	74–81	21,198.8	8,753.5	20,636.9	2,358
			33,720.9	12,251.0	27,793.0	2,269

From Table B, it can be seen that the four basic areas are not all valued equally. This table, covering eight years, masks much of the impact of knowledge gained over time and variations due to changing oil price expectations. Bids for the first mid-Atlantic sale, for example, were higher than for subsequent years due to the ultimately disappointing experience in the Baltimore Canyon. Additionally, bonus bids in 1974, 1979, and 1980, years when oil prices were increasing and future price expectations were high, were generally higher than for other years. The bids, then, are affected by the region, the state of knowledge of each region, and general expectations as to oil price movements.

Even during the relatively restricted leasing over the last eight years, not all the areas offered were bid on. This will continue to be true, as not all the acreage offered under the new program will be of interest. The big plus, however, is that with the broader range of offers, there is much more scope for bidders to apply their individual judgment and preference as to the areas likely to show the most profit. The number of bids per tract in all but the most exciting areas may well be reduced and the average bid per area may fall. But this will encourage more entrants into the bidding and provide much more scope for vision and entrepreneurial skill within the U.S. oil industry. Thus, more acres will be bid for by more concerns than has been the case previously. And, while the price bid per acre will almost certainly fall on average, the total amount bid will probably be up significantly from what it otherwise would have been.

The sales already on the books from the previous program can give us some idea of the change in anticipated value of the regions, but until we see the bids made for the first major regional sale – Central Gulf of Mexico in May, 1983 – the precise impact of the expanded lease program on the number of bids per tract and total funds bid can only be guessed at.

Previous Gulf of Mexico sales have averaged less than one million acres. This sale is proposed to be of 46 million acres. There have been less than three sales per year of Gulf of Mexico leases, with 1981 average costs per acre for successful bids being around $3,000, compared with about $4,500 in the previous two years. Given current oil price expectations, bids at the October sale (sale number 69 of the current leasing program) will probably be low by recent standards. If price expectations remain weak, the 1983 Gulf of Mexico sale may also have relatively low bids. The increased acreage offered, however, could easily raise the total sums bid by a factor of five. Assuming the policy on minimum acceptable bids is reasonable, the acreage leased could be up by a factor of eight or nine. This implies an average price per acre of around $1,000 for the 1983 sale with about 12 million acres being leased. It must be emphasized that this is only a guess. If this guess proves correct, however, and other areas show similar trends, then taken together receipts resulting from the revised program could easily reach $16 billion annually. This increase from an average of about $3.5 billion under the old program would have a fairly dramatic effect on the U.S. E&P program—not to mention government revenues. The offshore exploration program would be significantly increased, with a doubling of expected activity by 1990 being a very conservative estimate.



The funds to finance increased OCS expenditures by the petroleum industry can come from three sources—transfer of investment from U.S. onshore to U.S. offshore, transfer of investment from outside the U.S. to U.S. offshore, and increased debt financing. Since it takes some years for E&P increased penditures to pay off in increased cash flow from new production, there will have to be some transfer of effort from other areas in the early years. By 1990, however, the payoff will become apparent, and an increase in U.S. offshore production of 500-700 thousand barrels per day could be anticipated, which would have a positive balance of payments effect of over $15 billion per year. We continue to feel that the accelerated OCS program is a crucial step in the right direction.

Colin P. Carter

U.S. REFINERY MARGINS

As shown in Table 1, the tremendous deterioration of refinery margins since October, 1981 appears to have been reversed beginning in March. By May, margins at Type 1 refineries had surpassed last November's levels, while Type 2 refineries were close to breaking even on a gross margin basis. It is possible that when the June refiner acquisition cost data becomes available, Type 2 refineries will show a small positive gross margin for the first time since 1979. Price increases were posted across the board for all refined products on average in June, while the available evidence on crude costs indicates essentially no change.

TABLE 1 U.S. REFINERY MARGINS
(Dollars Per Barrel)

	Type 1 Refinery	Type 2 Refinery
1975	1.21	0.10
1976	2.01	0.31
1977	2.49	0.94
1978	2.39	0.10
1979	4.19	0.84
1980	4.09	−1.97
January, 1981	3.25	−1.44
February, 1981	2.28	−3.03
March, 1981	3.13	−2.60
April, 1981	4.00	−1.69
May, 1981 (R)	4.13	−1.53
June, 1981 (R)	4.59	−1.48
July, 1981	4.69	−1.57
August, 1981 (R)	4.75	−1.63
September, 1981	4.98	−1.30
October, 1981 (R)	4.98	−1.20
November, 1981 (R)	4.61	−1.40
December, 1981 (R)	4.10	−1.68
January, 1982 (R)	3.83	−1.74
February, 1982 (R)	2.94	−2.22
March, 1982 (P)	2.97	−1.77
April, 1982 (P)	3.06	−1.37
May, 1982 (E)	4.65	−0.22

R = Revised, E = Estimate, P = Preliminary

Note: Spread figures are calculated as follows:

	Motor Gasoline	Kerosine	Distillate Fuel	Residual Fuel
Type 1	50%	8%	25%	17%
Type 2	23%	8%	19%	52%

EUROPEAN REFINERY MARGINS

While crude oil prices on the spot market fell substantially during the first quarter of 1982 in Europe, contract prices were much less responsive. The decline we show in European oil prices in Table 2 represents our assessment of the changes in the cost of contract crude oil as well as product prices. Estimated refinery margins are shown in Table 3. The impact of the slide in product prices in Europe in the first quarter of 1982 is evident in the sharp drop in refinery margins for both high and low conversion refineries. The margins computed are gross margins, that is, they must cover both operating costs and profits. Thus a positive margin does not necessarily indicate that a profit was made. Even assuming a refinery running on spot crude purchased at an estimated average price of $29.50 per barrel, European refinery margins, in March, 1982, would still have been below those of December, 1981 for high conversion refineries.

TABLE 2 EUROPEAN CRUDE OIL AND PRODUCT PRICES
(Dollars Per Barrel)

	SEPT. 1981	DEC. 1981	MAR. 1982	APRIL 1982
Crude Oil	35.70	34.00	32.50	32.00
Gasoline	41.60	40.15	31.40	32.28
Naphtha	39.50	38.00	32.00	32.00
Middle Distillate	39.45	42.05	37.60	38.01
Residual Fuel	31.80	27.70	25.50	26.10

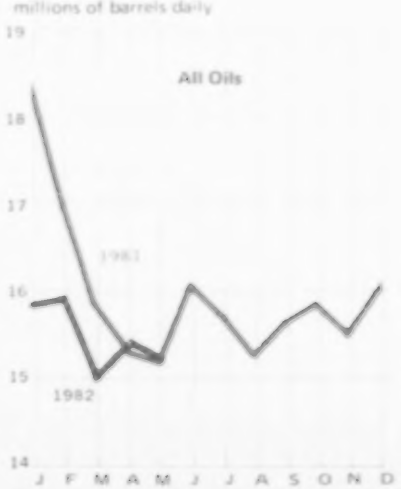
TABLE 3 EUROPEAN REFINERY MARGINS
(Dollars Per Barrel)

	SEPT. 1981	DEC. 1981	MAR. 1982	APRIL 1982
High Conversion	2.34	3.20	−0.59	0.47
Low Conversion	−0.24	−0.44	−2.74	−1.73

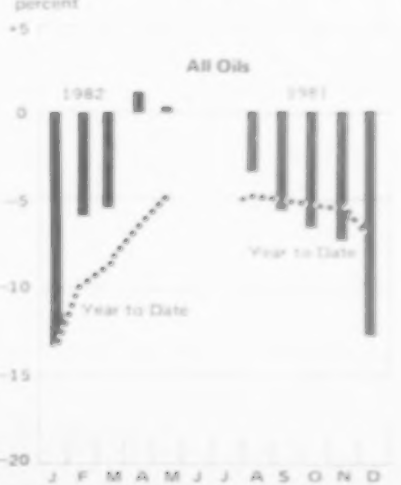
Note: High conversion yield: gasoline 30%, naphtha 10%, middle distillate 33%, residual fuel 27%.
Low conversion yield: gasoline 10%, naphtha 10%, middle distillate 25%, residual fuel 55%.

Demand For Petroleum Products

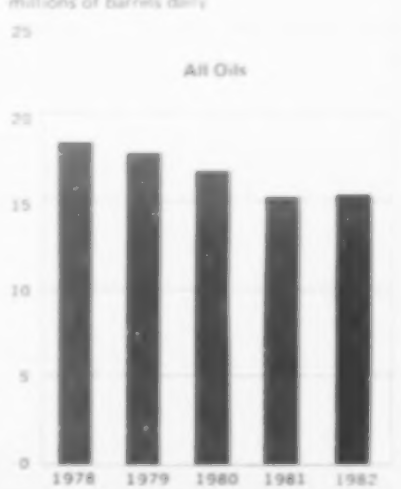
BY MONTH



CHANGE FROM YEAR AGO



MAY AVERAGES



JAPANESE REFINERY MARGINS

Crude oil and product prices in Japan are shown in Table 4.

TABLE 4

CRUDE OIL AND PRODUCT PRICES IN JAPAN

(Dollars Per Barrel)

	SEPT. 1981	DEC. 1981	MAR. 1982	APRIL 1982
Crude Oil	39.30	37.50	36.90	36.00
Gasoline	66.36	70.28	62.60	63.00
Naphtha	41.58	44.04	39.22	39.22
Middle Distillate	52.60	55.70	49.62	51.40
Residual Fuel	41.30	43.70	38.96	40.43

The resulting spreads are then shown in Table 5 and seem to be very large by European and U.S. standards. Recall that these spreads must cover operating costs and profit. Operating costs for Japan include a much greater level of interest payments than is common for the U.S. or Europe, but this does not fully explain the differences. Frankly, we are still investigating the issue.

TABLE 5

JAPANESE REFINERY MARGINS

(Dollars Per Barrel)

	SEPT. 1981	DEC. 1981	MAR. 1982	APRIL 1982
High Conversion	9.95	14.64	9.56	11.58
Low Conversion	7.04	11.55	6.82	9.00

Note: High conversion yield: gasoline 18%, naphtha 17%, middle distillate 30%, residual fuel 35%.

Low conversion yield: gasoline 11%, naphtha 9%, middle distillate 20%, residual fuel 60%.

U.S. SUPPLY/DEMAND

The data on supply and demand is now available for May. Although demand is still running below last year's level on a year-to-date basis, total demand in May was fractionally higher than it was in May, 1981. Demand for motor gasoline and distillates was up, while demand for residual fuel, used by industry and utilities, and the "All Other Oils" category, in which the major component is petrochemical feedstocks, continued to decline.

The increase in distillate demand was the most significant, over 11 percent in May, 1982 compared to May, 1981. Part of this increase may be due to restocking at the dealer level as well as at refineries. Stocks of motor gasoline fell by 14 million barrels in May, or 455 thousand barrels per day, to 213 million barrels, more than 45 million barrels below the year-ago level. On a days supply basis, stocks on May 31, 1982 were equal to 31.4 days of motor gasoline demand compared to 39.1 days last year.

Overall, stocks of all oils have been falling by more than 1.2 million barrels per day on average since the beginning of the year. This drawdown is more substantial than anything we have seen in the United States since the forced stock runoff in early 1979 following the fall of the Shah.

	MAY			3 MOS. AVERAGE			YEAR-TO-DATE		
	1982	1981	Change	1982	1981	Change	1982	1981	Change
	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –
PRIMARY DEMAND									
Motor Gasoline	6,778	6,608	2.6	6,551	6,498	0.8	6,332	6,437	- 1.6
(Unleaded)*	3,517	3,117	12.8	3,496	3,162	10.6	3,335	3,141	6.2
Jet Fuel	923	923	0.0	970	981	- 1.1	994	1,003	- 0.9
Kerosine	93	88	5.7	99	98	1.4	136	136	- 0.4
Distillate Fuel	2,661	1,395	11.1	2,776	2,610	6.4	2,983	3,059	- 2.5
Residual Fuel	1,591	1,769	- 10.1	1,728	1,899	- 9.0	1,914	2,219	- 13.8
All Other	3,200	3,416	- 6.3	3,118	3,358	- 7.1	3,148	3,447	- 8.7
Total Domestic Demand	15,246	15,199	0.3	15,244	15,444	- 1.3	15,507	16,302	- 4.9
Exports	835	595	40.3	831	584	42.4	825	576	43.4
Total Demand	16,081	15,794	1.8	16,075	16,028	0.3	16,332	16,878	- 3.2
New Supply									
Domestic	10,640	10,851	- 1.9	10,756	10,731	0.2	10,770	10,815	- 0.4
Crude Oil	8,689	8,496	2.3	8,688	8,547	1.7	8,684	8,553	1.5
Natural Gas Liquids	1,547	1,554	- 0.5	1,564	1,562	0.1	1,553	1,579	- 1.6
Other Supply	404	801	- 49.6	505	622	- 18.9	532	683	- 22.1
Imports	4,269	5,317	- 19.7	4,258	5,567	- 23.5	4,468	6,011	- 25.7
Crude Oil	2,977	3,881	- 23.3	2,854	4,149	- 31.2	2,970	4,406	- 32.6
Refined Products	1,292	1,436	- 10.0	1,404	1,418	- 1.0	1,498	1,605	- 6.7
Residual Fuel	645	735	- 12.2	701	674	4.1	768	796	- 3.5
All Other	642	701	- 7.7	702	745	- 5.7	730	809	- 9.8
Total New Supply	14,909	16,168	- 7.8	15,014	16,298	- 7.9	15,238	16,826	- 9.4
Crude Oil Refined	11,746	12,555	- 6.4	11,493	12,490	- 8.0	11,627	12,824	- 9.3
Stock Change	-1,172	374	–	-1,061	271	–	-1,095	-52	–
Stocks – End of Month in Million Barrels									
Gasoline	213	259	- 17.7						
Jet Fuel	41	45	- 7.5						
Kerosine	10	13	- 19.3						
Distillate Fuel	112	172	- 34.9						
Residual Fuel	54	79	- 30.9						
All Other	285	328	- 13.0						
Total Products	716	895	- 20.0						
Crude Oil	356	402	- 11.5						
Total – All Oils	1,072	1,297	- 17.3						

Totals may not add due to rounding
*Included in motor gasoline

Sources: *American Petroleum Institute*
Chase Manhattan Bank
Department of Energy